JOUL, Volume *4*

Supplemental Information

Role of Long-Duration Energy Storage

in Variable Renewable Electricity Systems

Jacqueline A. Dowling, Katherine Z. Rinaldi, Tyler H. Ruggles, Steven J. Davis, Mengyao Yuan, Fan Tong, Nathan S. Lewis, and Ken Caldeira

1. Model formulation

1.1. Nomenclature

Symbol	Unit	Description
g	kW	Generation technology (wind, solar)
v	kW	Energy conversion (electrolyzer, fuel cell)
s	kWh	Energy storage (PGP storage, battery storage)
$froms$	kW	Discharge from energy storage
tos	kW	Charge to energy storage
t	h	Time step, starting from 1 and ending at T
c_{capital}	\$/kW for generation or conversion \$/kWh for storage	(Overnight) capital cost
c_{fixed}	\$/kW/h for generation or conversion \$/kWh/h for storage	Fixed cost
$c_{\text{fixed O\&M}}$	\$/kW/yr	Fixed operating and maintenance (O&M) cost
c_{var}	\$/kWh	Variable cost
f	-	Capacity factor (generation technology)
h	h/year	Average number of hours per year
i	-	Discount rate
n	yrs	Project life
Δt	h	Time step size, i.e., 1 hour in the model
C	kW for generation or conversion kWh for storage	Capacity
D_t	kW	Dispatch at time step t
M_t	kWh	Demand at time step t
S_t	kWh	Energy remaining in storage at time step t
γ	1/yr	Capital recovery factor
δ	1/h	Storage decay rate, or energy loss per hour expressed as fraction of energy in storage
η	-	Storage charging efficiency
τ	h	Storage charging duration

Table S1: Model nomenclature

1.2. Cost calculations

Fixed cost of generation and conversion technologies (wind, solar, electrolyzer, fuel cell):

$$c^{g,v}_{fixed} = \frac{\gamma c^{g,v}_{capital} + c^{g,v}_{\text{fixed O\&M}}}{h}$$

Fixed cost of energy storage (PGP storage, battery storage):

$$c^s_{fixed} = \frac{\gamma c^s_{capital}}{h}$$

Capital recovery factor:

$$\gamma = \frac{i(1+i)^n}{(1+i)^n - 1}$$

1.3. Constraints

Capacity:

$$0 \leq C^{g,v,s} \qquad \forall g, v, s$$

Dispatch:

$$\begin{aligned}
0 \leq & D^g_t \leq C^g f^g && \forall g, t \\
0 \leq & D^v_t \leq C^v && \forall v, t \\
0 \leq & D^{\text{to s}}_t \leq \frac{C^s}{\tau^s} && \forall s, t \\
0 \leq & D^{textfroms}_t \leq \frac{C^s}{\tau^s} && \forall s, t \\
0 \leq & S^s_t \leq C^s && \forall s, t \\
0 \leq & D^{\text{from s}_t} \leq S^s_t(1-\delta^s) && \forall s, t
\end{aligned}$$

Storage energy balance:

$$\begin{aligned}
S_1 &= (1-\delta^s) S_t \Delta t + \eta^s D^{\text{to s}}_T \Delta t - D^{\text{from s}}_T \Delta t && \forall s \\
S_{t+1} &= (1-\delta^s) S_t \Delta t + \eta^s D^{\text{to s}}_t \Delta t - D^{\text{from s}}_t \Delta t && \forall s, t \in 1, ..., (T-1)
\end{aligned}$$

System energy balance:

$$\sum_g D^g_t \Delta t + D^{\text{from s}}_t \Delta t = M_t + D^{\text{to so}}_t \Delta t \qquad \forall g, t$$

1.4. Objective function

$$\text{minimize(system cost)}$$

$$\text{system cost} =$$

$$\sum_g c^g_{\text{fixed}} C^g + \sum_g \left(\frac{\sum_t c^g_{\text{var}} D^g_t}{T}\right) + \sum_v c^v_{\text{fixed}} C^v +$$
$$\sum_s c^s_{\text{fixed}} C^s + \frac{\sum_t c^{\text{to s}}_{\text{var}} D^s_t}{T} + \frac{\sum_t c^{\text{from s}}_{\text{var}} D^s_t}{T}$$

2. Supplemental experimental procedures

2.1. Model limitations

The linear model considers scenarios with perfect foresight, perfectly efficient markets, and no transmission losses. Despite these simplifications, key findings of our study are in accord with and build on a similar European electricity system that included transmission modeling.[1] Simulations for the West, East, and Texas Interconnects further show the robustness of our results (Figure S7). The system was confined solely to the electricity sector and did not consider conversion of electricity into fuel to serve other sectors such as transportation or heating. We did not include carbon capture with natural gas because the regulatory and legislative environment considered is confined to zero-carbon and renewable electricity sources (Table S2). We evaluate the system over an hourly timescale. Other technologies, including perhaps batteries, are assumed to provide short term (minutes to hours) smoothing of power variability. Additionally, although we include a project lifetime and self-discharge rate for batteries, we do not track battery deterioration due to cycling. Previous studies of electricity systems for the U.S. with high variable renewable penetration depend on future projections, consider shorter time periods, do not satisfy hourly demand with the statutorily required resource availability, and/or use highly complex models.[2]

2.2. Storage technology costs

In Table S3 we list cost and performance metrics for a variety of energy storage technologies. This table builds off of the compiled information in Luo et al.[3] for the more mature technologies: pumped hydropower, compressed air energy storage, flywheels, capacitors, and lead-acid batteries; original works are cited in the table itself. More rapidly developing technologies, such as Li-ion batteries, redox flow batteries, and PGP cite more recent literature including references[4,5] and those listed for the base case in Table 1. For some storage technologies (pumped hydropower, compressed air, redox flow, and PGP) the power and energy capacities for a given project can be sized independently. For these technologies, and all of the others, we provide the total capital cost divided by the power and again by the energy capacity of typical systems characterized in the literature in Figure 1. In these cases, the flexibility of independently sizing power and energy capacities for a given project for the LDS candidates is not shown in this table. The values depicted in Figure 1 are shown in Table S3.

The increased flexibility of the four LDS technologies: pumped hydropower storage (PHS), compressed air energy storage (CAES), redox flow batteries (potentially because of the ability to separate power and energy capacities), and PGP is shown in Table S3 where capital costs are split into power-related capital costs and energy-related capital costs. The costs of PHS projects are highly site and project specific;[6] depending on the local geology, a dam capable of storing one quantity of water in one valley, could potentially store a very different quantity in another valley necessitating caution when extrapolating PHS costs. The conversion of pressurized air to power in a CAES systems relies on multiple stages of air expansion with some involving gas turbines.[7] This makes CAES inconsistent with with the zero carbon emissions and 100% RE goal of this analysis. Despite this, we include CAES in Table S4. We emphasize that either gas produced from a carbon neutral process would be needed for the turbine or carbon capture and storage of the CO_2 from the exhaust. Either option would increase the presented CAES costs.

3. Supplementary figures and tables

State	Max renewable requirement	Electricity sector end-state
Virginia[8]	100% RE by 2050[a]	100% RE-only by 2050[a]
Maine[9]	80% RE by 2030	100% RE-only by 2045
Hawaii[10]	100% RE by 2050	100% RE-only by 2045
New Mexico[11]	80% RE by 2040	Zero-carbon by 2045
New York[12]	70% RE by 2030	Zero-carbon by 2040[b]
California[13]	60% RE by 2030	Zero-carbon by 2045
Nevada[14]	50% RE by 2030	Zero-carbon by 2045[c]
Washington[15]	only zero-carbon requirements	Zero-carbon by 2045
Puerto Rico[16]	100% RE by 2050	100% RE-only by 2050
Washington D.C.[17]	100% RE by 2032	100% RE-only by 2032

Table S2: **100% clean power state laws: renewable vs. zero-carbon requirements.** Several states and jurisdictions have mandated the adoption of 100% clean electricity systems by 2030-2050. The term 'zero-carbon' is broader than renewable energy (RE), as it generally includes technologies like nuclear and large-scale hydropower, for example, that are not strictly renewable by policy definition in most state Renewable Portfolio Standards (RPS). RE technologies include wind, solar, batteries, renewable hydrogen, and others. Natural gas with CCS is currently not eligible as a "zero-carbon resource" for meeting clean energy mandates in states like California (although the CEC is actively discussing their eligibility for this purpose.)[18] Natural gas with CCS may be permitted in net "zero-emissions" electricity systems in states like New York. Most states with 100% clean power laws have mandated the adoption of primarily RE technologies prior to zero-carbon or RE-only electricity system end-states. RPS are also used to specify the capacities of certain RE technologies such as wind, solar, and energy storage to be deployed. Iowa was the first state to establish an RPS and since then, more than half of states have established RE targets.[19] While most state RE targets are between 10% and 45%, 14 states—California, Colorado, Hawaii, Maine, Maryland, Massachusetts, Nevada, New Mexico, New Jersey, New York, Oregon, Vermont, Virginia, Washington, as well as Washington, D.C., Puerto Rico, and the Virgin Islands—have requirements of 50% or greater.[19]

[a]Virginia's RE targets apply to 'Phase I' and 'Phase II' investor-owned utilities.

[b]New York's goal involves reducing 100% of the electricity sector's greenhouse gas emissions by 2040 as compared to 1990 levels.

[c]Nevada's 50% RE by 2030 target is binding; its 100% zero-carbon by 2050 target is non-binding.

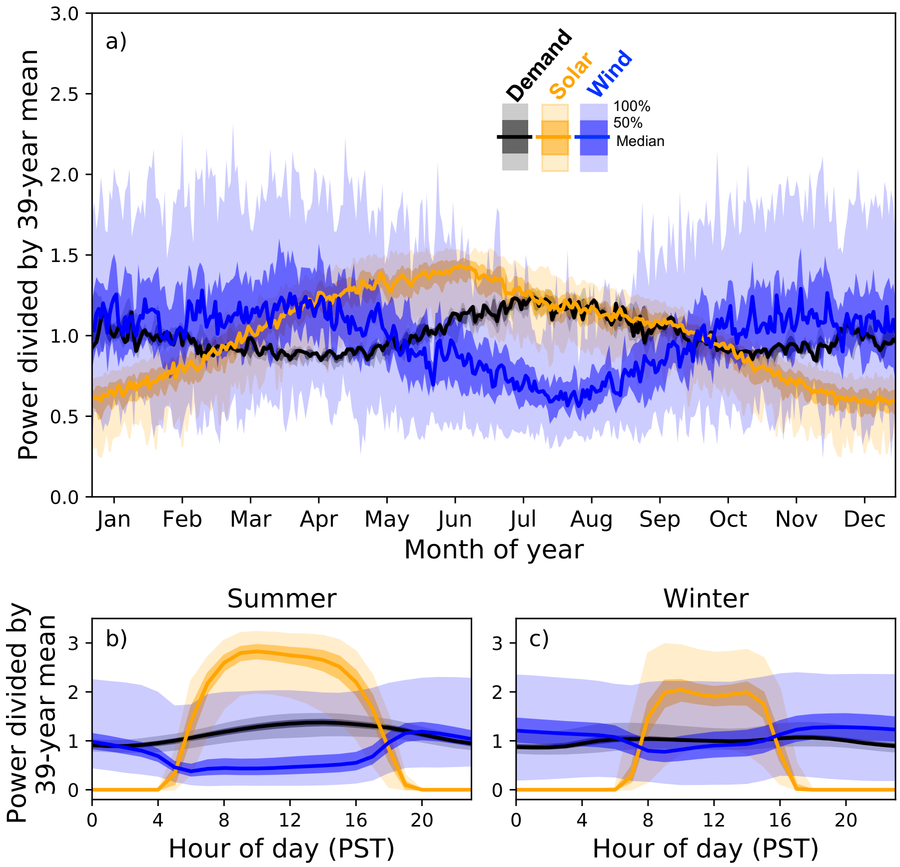


Figure S1: **Resource and demand variability.** The temporal variability of wind (blue) and solar (yellow) supply and electricity (black) demand over the contiguous United States from 1980-2018. Variability is shown over a) daily averaged, seasonal, b) hourly summer (June, July, and August), and c) hourly winter (December, January, February) timescales. The dark lines represent the median value, the darker shading represents the 25^{th} to 75^{th} percentile of data, and the lighter shading represents the 0^{th} to 100^{th} percentile of data. All data is normalized to its respective 39 year mean. See methods section on wind and solar capacity factors for more details. Data used in our analysis is displayed here. The plotting code is adapted.[20]

storage technology	total capital cost ($/kW)	total capital cost ($/kWh)	typical energy/ power	typical round-trip efficiency RTE (%)	typical lifetime (years)
flywheel	250-350 [7]	1,000-5,000 [7]	$\ll$1 [7,21]	~90–95 [7]	~15 [7]
capacitor	200-400 [7]	500-1,000 [7]	$\ll$1–1 [7]	~60-70 [7]	~5 [7]
lead–acid	300-600 [7]	200-400 [7]	<1-10 [7,22]	70-80, [7] 63-90, [22] 75–80 [23]	5-15 [7]
Li-ion	280-513, 488-980, 898-1,874 [24]	295-540,[e] 257-517,[e] 237-494[e] [24]	1, 2, 4 [24]	86-90 [24]	10 [24]
redox flow[a] (vanadium)	1,027-1,155, 1,788-1,956 [5]	4,106-4,620, 447-489 [5]	0.25, 4 [5]	70-78, 76-79 [5]	20 [5]
pumped hydropower[a]	2,500-4,300, [25] 2,000-4,000, [21] 975 [26]	5-100, [7] 97.5 [26]	1-24+, [7] 6-10, [25] 10, [21] 10 [26]	70-85, [7] 70-80 [21]	40-60, [7] 50[f]
compressed air[a]	400-800, [7] 800-1,000, [21] 650 [26]	2-50, [7] 16 [26]	1-24, [7] 40 [26]	42, [7] 45-60 [21]	20-40, [7] 30[f]
power-to-gas-to-power[a]	6,500-6,600,[b] 5,300-11,000[c]	5.6-8.8,[b] 4.6-14[c]	740-1,200[b]	electrolyzer 70,[d] fuel cell 70,[d] RTE 49[d]	electrolyzer 12.5,[d] cavern 30,[d] fuel cell 20[d]

Table S3: Technical characteristics of energy storage technologies with cost values reported as total capital costs divided by typical power and energy capacities.
[a]Technologies with more easily separated power and energy capacities and costs; values for the split costs for these technologies are include in Table S4.
[b]Characteristics for the specific PGP system used in this analysis and optimized using one year of 2018 demand and resource data and again with 6 years of 2013-2018 data.
[c]These values consider the two scenarios in the [b] note and the original uncertainty in fuel cell capital costs of 4,600-10,000$/kW instead of using the base case value of 5,854 $/kW. The PGP systems were not re-optimized based on the low and high fuel cell values.
[d]References in Table 1.
[e]Values originally reported based on nameplate energy storage, converted to usable energy by dividing by sqrt(0.9), where 90% is approximately the round-trip efficiency.
[f]Exact values used in Figure 7b.

storage technology	power-related capital cost ($/kW)	energy-related capital cost ($/kWh)
redox flow (vanadium)	941-1,143 [5]	196-356 [5]
pumped hydropower	600,[c, 26] 1,200 [27]	37.5,[c, 26] 75 [27]
compressed air	580,[c, 26] 595 (€/kW),[a, 28] 700 [27]	1.75,[c, 26] 2 (€/kWh),[28] 5 [27]
power-to-gas-to-power	6,380[b]	0.16

Table S4: Technical characteristics of candidate long duration energy storage technologies. Costs are split into power-related capital costs and energy-related capital costs.

[a]Based on 356.4 $/kW for the properly sized turbine and compressor plus 238.8 $/kW$_{turbine}$ for "other investment costs."[28]

[b]Based on 1,058 $/kW electrolyzer and 5,854 $/kW fuel cell costs (Table 1) and a 1:2 electrolyzer-to-fuel cell capacity ratio (results of the 2018 base case).

[c]Exact values used in Figure 7b. All storage variable costs are modeled as zero $/kWh.

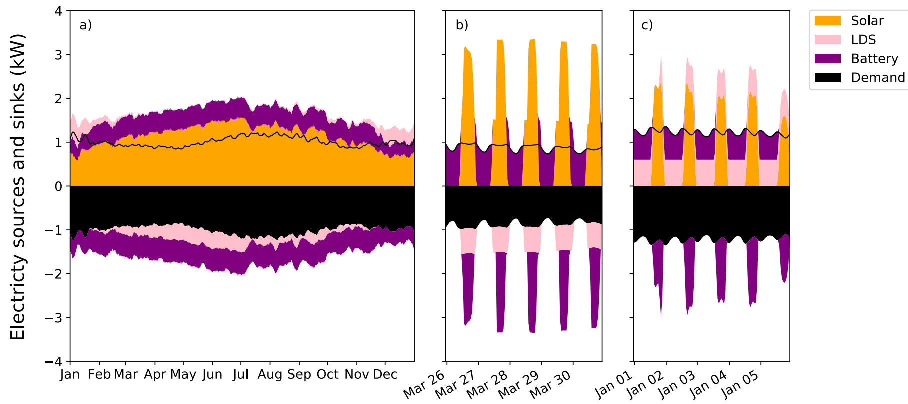


Figure S2: **Dispatch curves: solar, LDS, batteries.** a) Annual view of the solar only generation case for 2018. Batteries were charged and discharged on the daily cycle. LDS was charged during daily solar peaks and was used in wintertime during the seasonal low. b) 5-day period of maximum battery dispatch (starting at 08:00PM CST). Batteries were discharged, and LDS was simultaneously charged each day. c) 5-day period of maximum LDS dispatch (starting at 06:00PM CST). At peak daytime, excess solar and dispatched LDS were used to charge batteries. LDS and batteries met demand at night.

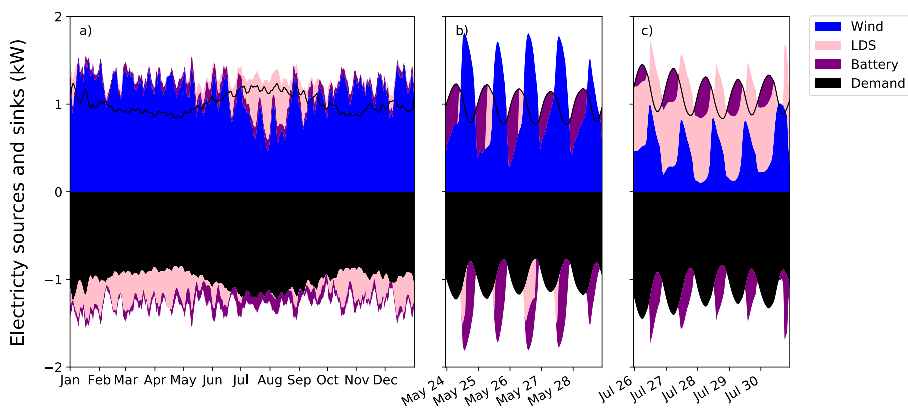
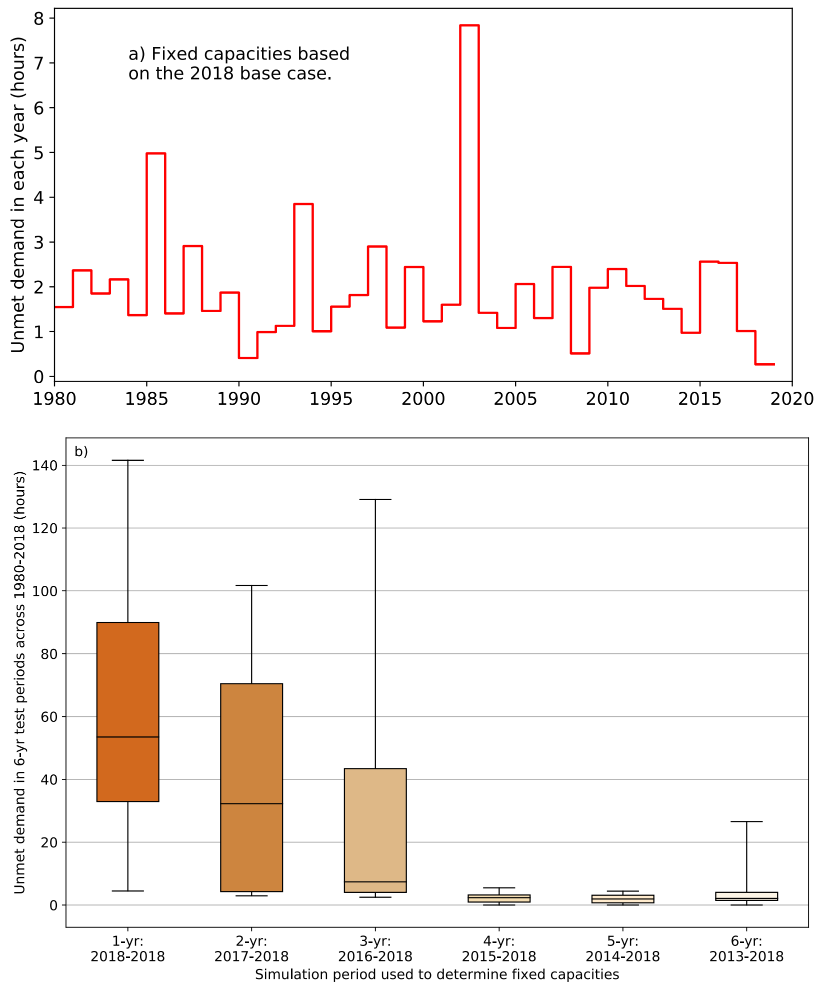


Figure S3: **Dispatch curves: wind, LDS, batteries.** a) Annual view of the wind only generation case for 2018. LDS was discharged primarily in the summer when the wind resource is least abundant. b) 5-day period of maximum battery electricity source (starting at 07:00AM CST). Batteries and LDS capture nighttime wind resource peaks. Both LDS and batteries meet demand during the day. c) 5-day period of maximum LDS electricity source (starting at 11:00AM CST). Simultaneous LDS discharge and battery charge occurred each night.



Fixed capacity	Solar (1 = mean U.S. demand)	Wind (1 = mean U.S. demand)	Battery (h of mean U.S. demand)	LDS (h of mean U.S. demand)	Conversion to LDS (1 = mean U.S. demand)	Conversion from LDS (1 = mean U.S. demand)
1-yr: 2018-2018	1.0296	2.4814	1.6841	393	0.2706	0.5335
2-yr: 2017-2018	1.0077	2.4382	1.6074	477	0.2846	0.5678
3-yr: 2016-2018	1.0546	2.3634	1.8687	551	0.2696	0.5718
4-yr: 2015-2018	0.9400	2.4262	1.6987	723	0.3179	0.6062
5-yr: 2014-2018	1.0293	2.3307	1.9466	745	0.3211	0.5933
6-yr: 2013-2018	1.0329	2.3211	1.9599	699	0.3143	0.5954

Figure S4: **Fixed capacities based on asset builds from various simulations.** The cost of unmet demand was set to \$10/kWh. a) Hours of unmet demand in each year over the 39 year period when specifying capacities based on results from the 2018 base case. Asset builds based on a single year are not always robust for other years. b) Fixed capacities based on 1-, 2-, 3-, 4-, 5-, and 6-yr asset builds from the 2010s (capacities shown in the table where mean demand over the full data set was 457 GW). Unmet demand met (hours) based on these capacities is shown for 6-year test periods across the data set 1980-2018 (7 data points per box). While longer horizon modeling more accurately predicts needs, four-year simulations are not necessarily enough to meet NERC reliability standards.[29] More detailed studies are needed to determine how many simulation years are enough.

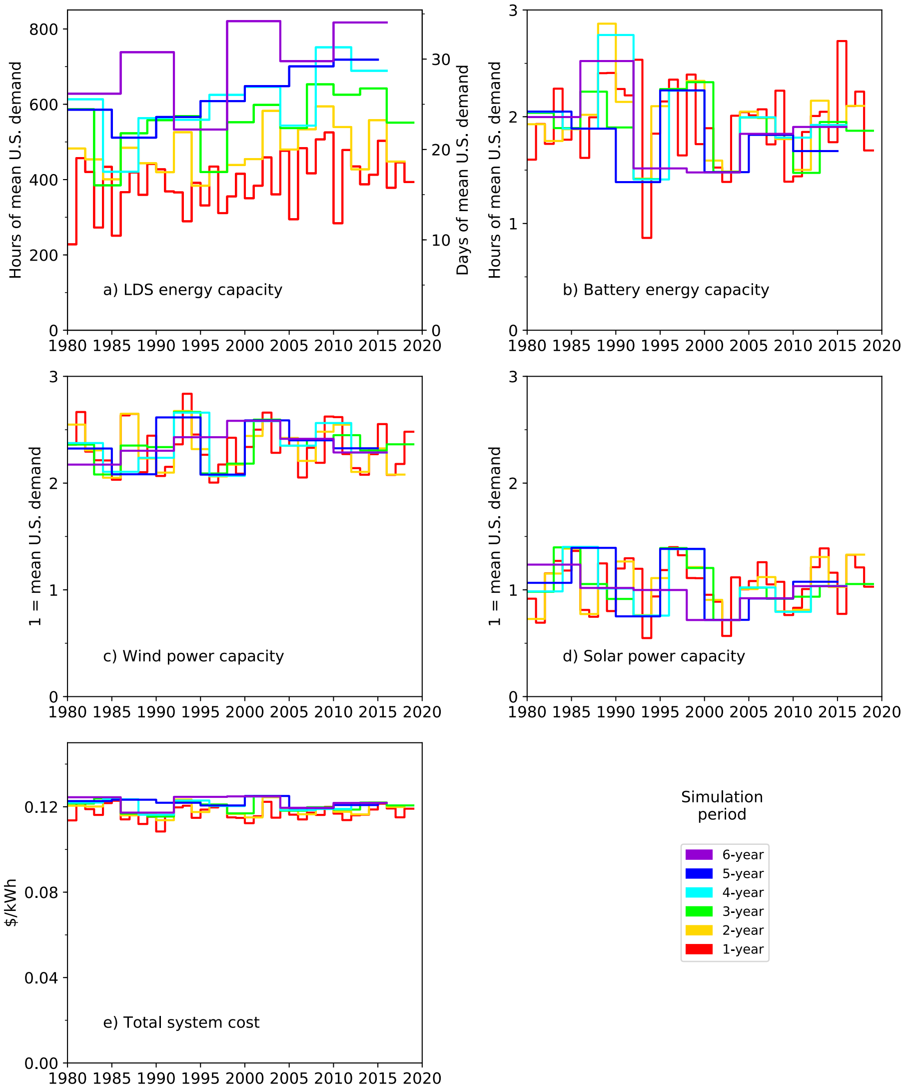


Figure S5: **Multiple year simulations: capacities.** 1-, 2-, 3-, 4-, 5-, and 6-year simulations were performed across all 39 years of wind and solar data available (1980 to 2018) for the contiguous U.S. The horizontal sections of the lines represent the optimized capacity for the periods simulated. Presented here are results for a) LDS energy capacity, b) battery energy capacity, c) wind power capacity, d) solar power capacity e) total system costs. In least-cost systems, longer simulation lengths resulted in larger installed storage capacities for LDS. System costs were ∼0.12 $/kWh for all simulation lengths.

Simulation length (across 39 years, 1980-2018)	**Data type**	**Total system cost ($/kWh)**	**LDS energy capacity (hours of mean U.S. demand)**	**Battery energy capacity (hours of mean U.S. demand)**	**Wind power capacity (1 kW = mean U.S. demand)**	**Solar power capacity (1 kW = mean U.S. demand)**
1-yr periods (start years: 1980, 1981, 1982, 1983, 1984, 1985, 1986, 1987, 1988, 1989, 1990, 1991, 1992, 1993, 1994, 1995, 1996, 1997, 1998, 1999, 2000, 2001, 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010, 2011, 2012, 2013, 2014, 2015, 2016, 2018)	max Q3 median Q1 min spread	0.123 0.119 0.116 0.115 0.108 13.0 %	525.28 438.12 393.53 357.45 228.1 130.0 %	2.71 2.22 1.99 1.74 0.86 213.0 %	2.84 2.47 2.3 2.16 2.0 41.0 %	1.4 1.21 1.11 0.9 0.55 155.0 %
2-yr periods (start years: 1980, 1982, 1984, 1986, 1988, 1990, 1992, 1994, 1996, 1998, 2000, 2002, 2004, 2006, 2008, 2010, 2012, 2014, 2016)	max Q3 median Q1 min spread	0.124 0.121 0.119 0.117 0.114 9.0 %	594.35 529.7 454.44 433.0 383.73 55.0 %	2.87 2.12 1.99 1.78 1.42 102.0 %	2.68 2.51 2.32 2.14 2.05 30.0 %	1.39 1.24 1.03 0.81 0.72 94.0 %
3-yr periods (start years: 1980, 1983, 1986, 1989, 1992, 1995, 1998, 2001, 2004, 2007, 2010, 2013, 2016)	max Q3 median Q1 min spread	0.125 0.122 0.121 0.118 0.115 8.0 %	653.02 598.4 557.8 536.79 384.76 70.0 %	2.32 2.04 1.9 1.83 1.42 64.0 %	2.67 2.4 2.35 2.31 2.08 28.0 %	1.4 1.05 1.02 0.92 0.72 94.0 %
4-yr periods (start years: 1980, 1984, 1988, 1992, 1996, 2000, 2004, 2008, 2012, 2016)	max Q3 median Q1 min spread	0.125 0.123 0.122 0.119 0.116 7.0 %	751.28 646.51 613.24 558.93 420.82 79.0 %	2.77 2.04 1.92 1.8 1.41 96.0 %	2.66 2.56 2.35 2.24 2.07 29.0 %	1.4 1.04 1.01 0.79 0.72 95.0 %
5-yr periods (start years: 1980, 1985, 1990, 1995, 2000, 2005, 2010, 2015)	max Q3 median Q1 min spread	0.125 0.123 0.122 0.121 0.119 5.0 %	718.57 674.43 608.48 575.92 511.4 41.0 %	2.25 1.97 1.83 1.58 1.39 62.0 %	2.62 2.49 2.33 2.2 2.08 26.0 %	1.39 1.23 1.07 0.84 0.72 94.0 %
6-yr periods (start years: 1980, 1986, 1992, 1998, 2004, 2010, 2016)	max Q3 median Q1 min spread	0.125 0.125 0.123 0.12 0.117 6.0 %	820.78 797.47 726.43 649.74 532.92 54.0 %	2.52 1.97 1.87 1.6 1.48 71.0 %	2.58 2.43 2.36 2.29 2.17 19.0 %	1.24 1.03 1.01 0.94 0.72 72.0 %

Table S5: **Distribution of capacities for various simulation lengths.** This data table supports Figure S5 and 5. Spread is defined as the relative difference between the max and the min: (max-min)/min $\times$ 100. The maximum is "spread" % greater than the minimum.

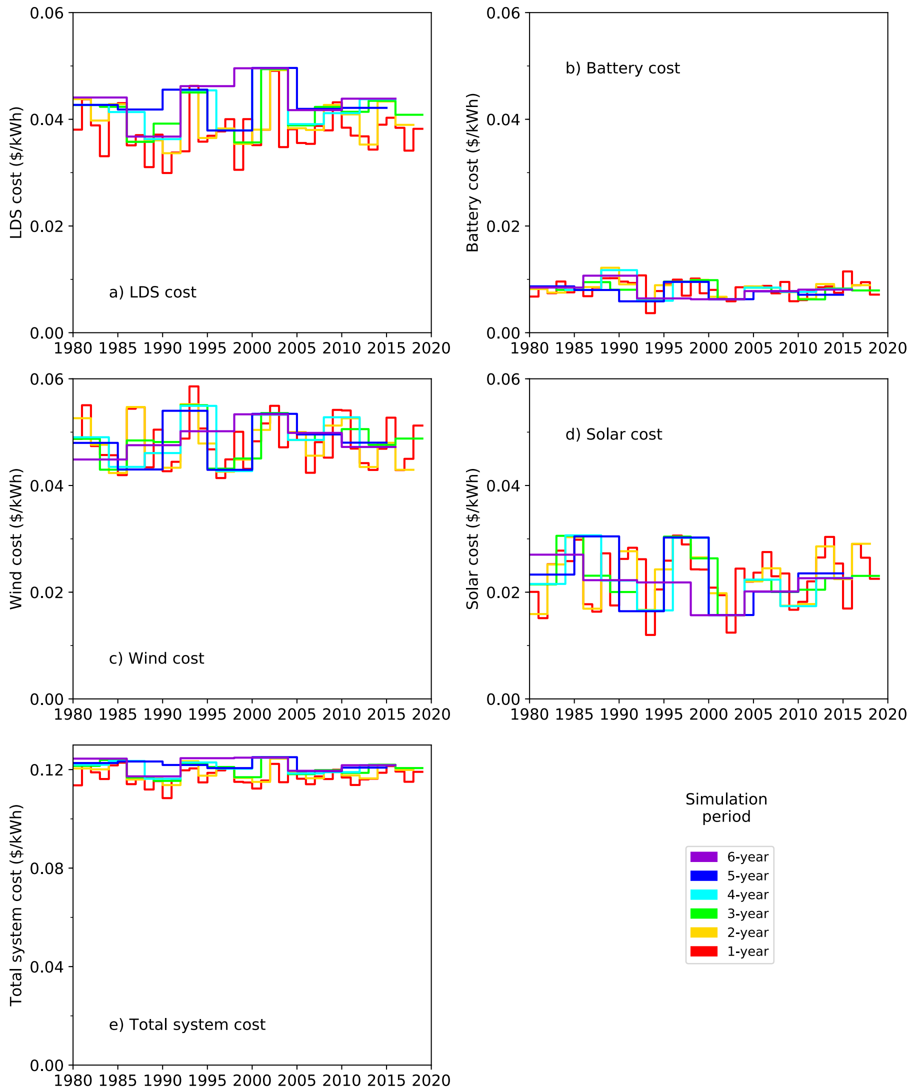
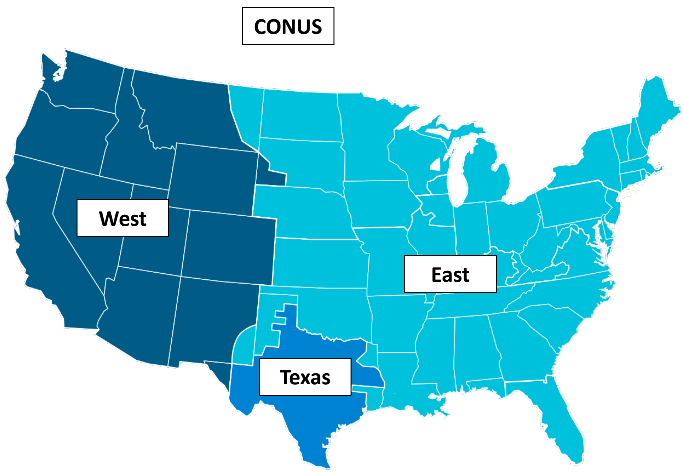


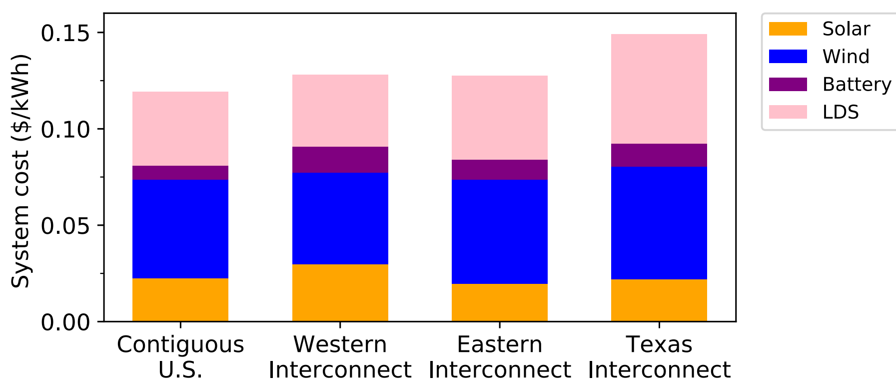
Figure S6: **Multiple year simulations: costs.** 1-, 2-, 3-, 4-, 5-, and 6-year simulations were performed across all 39 years of wind and solar data available (1980 to 2018) for the contiguous U.S. The horizontal sections of the lines represent the optimized investment in each technology for the periods simulated. Presented here are results for a) LDS cost, b) battery cost, c) wind cost, d) solar cost e) total system costs. LDS and wind technologies dominate system investments in all simulations periods across 1980-2018.

Simulation length (across 39 years, 1980-2018)	**Data type**	**Total system cost ($/kWh)**	**LDS cost ($/kWh)**	**Battery cost ($/kWh)**	**Wind cost ($/kWh)**	**Solar cost ($/kWh)**
1-yr periods (start years: 1980, 1981, 1982, 1983, 1984, 1985, 1986, 1987, 1988, 1989, 1990, 1991, 1992, 1993, 1994, 1995, 1996, 1997, 1998, 1999, 2000, 2001, 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010, 2011, 2012, 2013, 2014, 2015, 2016, 2018)	max	0.123	0.049	0.011	0.059	0.031
	Q3	0.119	0.039	0.009	0.051	0.026
	median	0.116	0.038	0.008	0.047	0.024
	Q1	0.115	0.035	0.007	0.045	0.02
	min	0.108	0.03	0.004	0.041	0.012
	spread	12.0 %	64.0 %	213.0 %	41.0 %	155.0 %
2-yr periods (start years: 1980, 1982, 1984, 1986, 1988, 1990, 1992, 1994, 1996, 1998, 2000, 2002, 2004, 2006, 2008, 2010, 2012, 2014, 2016)	max	0.124	0.049	0.012	0.055	0.03
	Q3	0.121	0.043	0.009	0.052	0.027
	median	0.119	0.038	0.008	0.048	0.022
	Q1	0.117	0.036	0.008	0.044	0.018
	min	0.114	0.034	0.006	0.042	0.016
	spread	9.0 %	46.0 %	102.0 %	30.0 %	94.0 %
3-yr periods (start years: 1980, 1983, 1986, 1989, 1992, 1995, 1998, 2001, 2004, 2007, 2010, 2013, 2016)	max	0.125	0.049	0.01	0.055	0.031
	Q3	0.122	0.043	0.009	0.05	0.023
	median	0.121	0.041	0.008	0.049	0.022
	Q1	0.118	0.039	0.008	0.048	0.02
	min	0.115	0.036	0.006	0.043	0.016
	spread	8.0 %	39.0 %	64.0 %	28.0 %	94.0 %
4-yr periods (start years: 1980, 1984, 1988, 1992, 1996, 2000, 2004, 2008, 2012, 2016)	max	0.125	0.05	0.012	0.055	0.031
	Q3	0.123	0.044	0.009	0.053	0.023
	median	0.122	0.041	0.008	0.049	0.022
	Q1	0.119	0.039	0.008	0.046	0.017
	min	0.116	0.036	0.006	0.043	0.016
	spread	7.0 %	37.0 %	96.0 %	29.0 %	95.0 %
5-yr periods (start years: 1980, 1985, 1990, 1995, 2000, 2005, 2010, 2015)	max	0.125	0.05	0.01	0.054	0.03
	Q3	0.123	0.044	0.008	0.052	0.027
	median	0.122	0.042	0.008	0.048	0.023
	Q1	0.121	0.042	0.007	0.045	0.018
	min	0.119	0.038	0.006	0.043	0.016
	spread	5.0 %	31.0 %	62.0 %	26.0 %	94.0 %
6-yr periods (start years: 1980, 1986, 1992, 1998, 2004, 2010, 2016)	max	0.125	0.05	0.011	0.053	0.027
	Q3	0.125	0.046	0.008	0.05	0.023
	median	0.123	0.044	0.008	0.049	0.022
	Q1	0.12	0.042	0.007	0.047	0.021
	min	0.117	0.037	0.006	0.045	0.016
	spread	6.0 %	35.0 %	71.0 %	19.0 %	72.0 %

Table S6: **Distribution of costs for various simulation lengths.** This data table supports Figure S6 and Figure 5. Spread is defined as the relative difference between the max and the min: (max-min)/min $\times$ 100. The maximum is "spread" % greater than the minimum.



(a) Contiguous U.S. and its three interconnects



(b) System costs of the contiguous U.S. its three interconnects

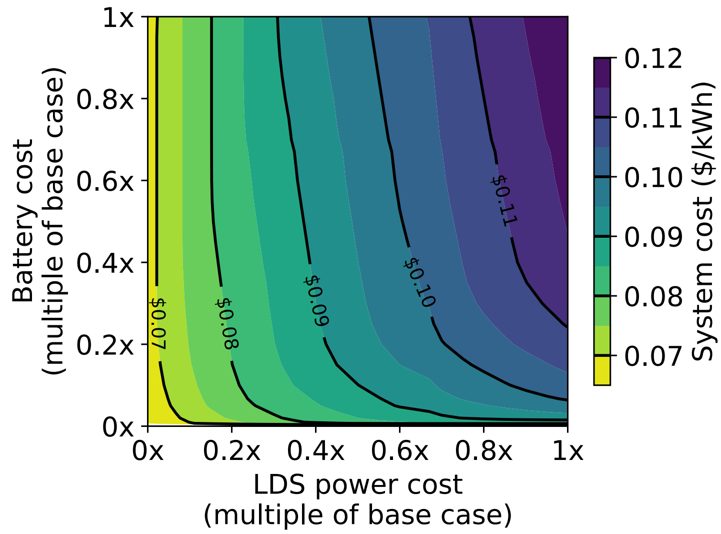
Figure S7: **System costs of different geographical regions.** System costs for the contiguous U.S. are compared to costs for systems confined to three largely independent interconnects: West, East, and Texas. Stacked areas in each bar represent the cumulative contribution of each technology to total system cost over the optimization period (2018). For each interconnect, the least-cost system includes substantial LDS and wind investment (66%, 76%, and 77% of total system cost for West, East, and Texas, respectively). The increased variability of wind and solar in small regions (such as Texas) requires compensation with more storage from both LDS and batteries. The map of the interconnects is adapted.[30] Table S7 supports this figure.

Region	**Wind**	**Solar**	**LDS**	**Battery**	**Total system cost ($/kWh)**
Contiguous U.S.	0.05	0.02	0.04	0.01	0.12
Western Interconnect	0.05	0.03	0.04	0.01	0.13
Eastern Interconnect	0.05	0.02	0.04	0.01	0.13
Texas Interconnect	0.06	0.02	0.06	0.01	0.15

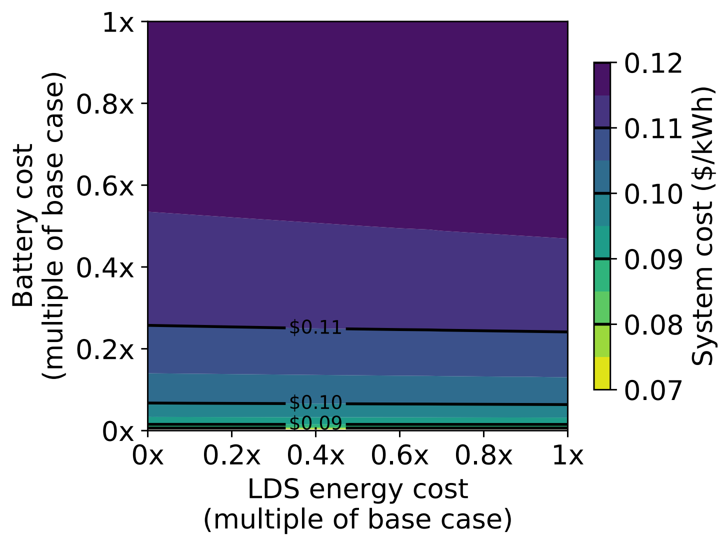
Table S7: **System costs of different geographical regions.** This data table supports Figure S7. Costs in $/kWh represent each technology's contribution to the total system cost. Costs for LDS include both power-related and energy-related costs. While rounded results are displayed in the table, exact values were used for secondary calculations.

Technology mix	**Wind**	**Solar**	**LDS**	**Battery**	**Total system cost ($/kWh)**
solar-battery	-	0.18	-	0.10	0.28
solar-LDS	-	0.12	0.13	-	0.25
solar-LDS-battery	-	0.09	0.05	0.05	0.19
wind-battery	0.18	-	-	0.05	0.23
wind-LDS	0.07	-	0.09	-	0.17
wind-LDS-battery	0.07	-	0.05	0.02	0.15
solar-wind-battery	0.09	0.04	-	0.02	0.14
solar-wind-LDS	0.05	0.02	0.06	-	0.13
solar-wind-LDS-battery	0.05	0.02	0.04	0.01	0.12

Table S8: **System costs with different technology combinations.** This data table supports Figure 6. Costs in $/kWh represent each technology's contribution to the total system cost. Costs for LDS include both power-related and energy-related costs. While rounded results are displayed in the table, exact values were used for secondary calculations.



(a) LDS power-capacity cost and battery total cost reductions



(b) LDS energy-capacity cost and battery total cost reductions

Figure S8: **Limiting factors of LDS and batteries.** Battery costs are varied as a total capacity cost while LDS energy capacity and power capacity costs are varied independently. a) Power-capacity and b) energy-capacity costs were reduced from base case assumptions (1x) to free (0x), and total system costs were plotted as contour lines ($/kWh). Each data point was a new simulation in which capacity and dispatch of each technology, including wind and solar generation, were reoptimized in response to each value of the conversion and storage costs. For batteries, we varied the total costs and maintained a 6 hour charging duration. Total electricity system costs in a least-cost system decreased substantially with reductions in LDS conversion costs and, to a lesser extent, battery storage costs. This behavior occurs because the use of LDS in the least-cost system is limited by power capacity, whereas the use of batteries is limited by their energy capacity.

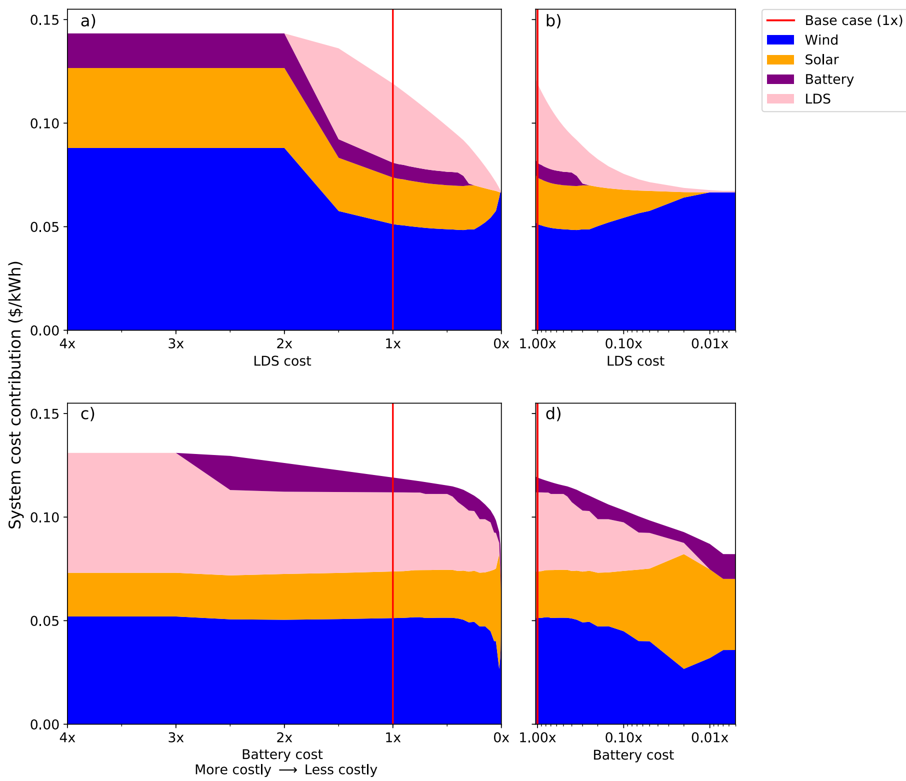


Figure S9: **System cost contributions vs. LDS and battery costs.** a, b) LDS and c, d) battery costs were varied from four times (4x) more costly than base case assumptions (1x) to free (0x). The contributions of each technology to the system cost for year 2018 are presented. Linear scale plots (a, c) showed that eliminating LDS from a least-cost electricity system required a ∼2x increase in costs relative to current costs, and batteries required a ∼3.5x increase in costs. The log scale plot of LDS cost reduction (b) showed that a ∼4-fold decrease in LDS costs (0.25x) eliminated batteries and reduced solar generation cost contribution. The log scale plot of battery cost reduction (d), showed that a ∼100-fold (0.01x) decrease in battery costs led to elimination of LDS and reduced cost contribution associated with wind generation.

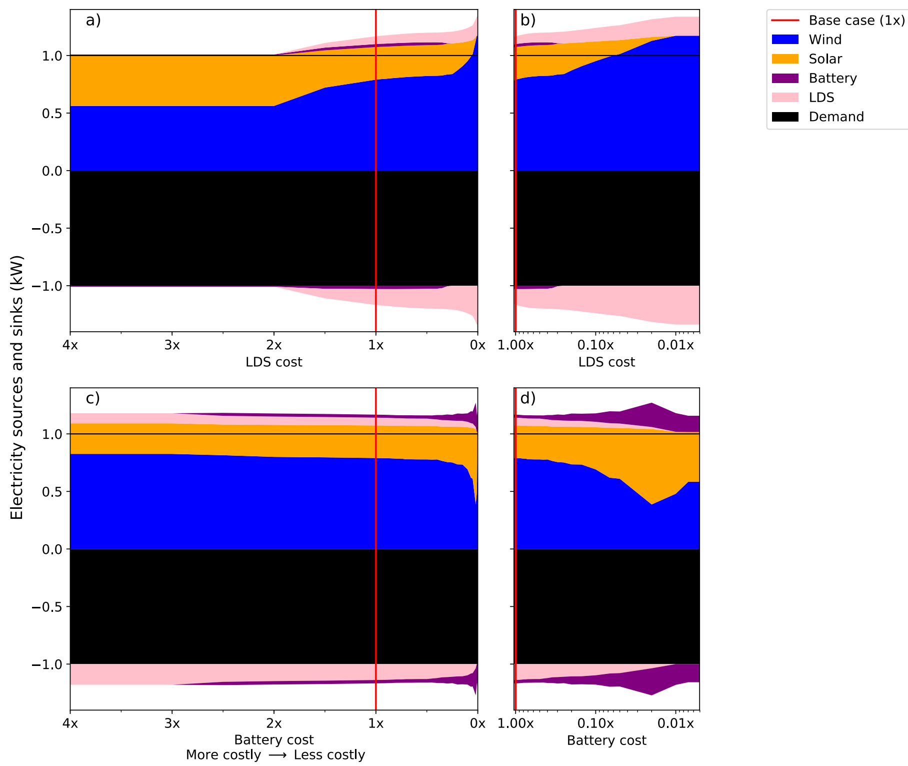
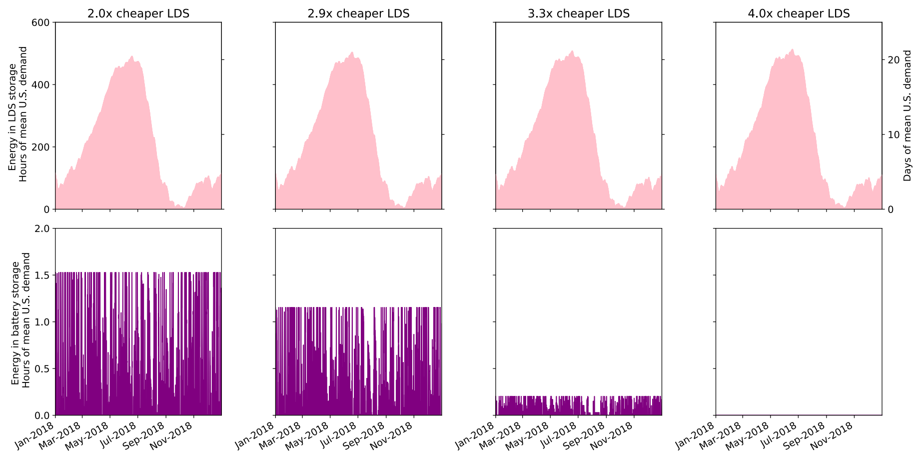
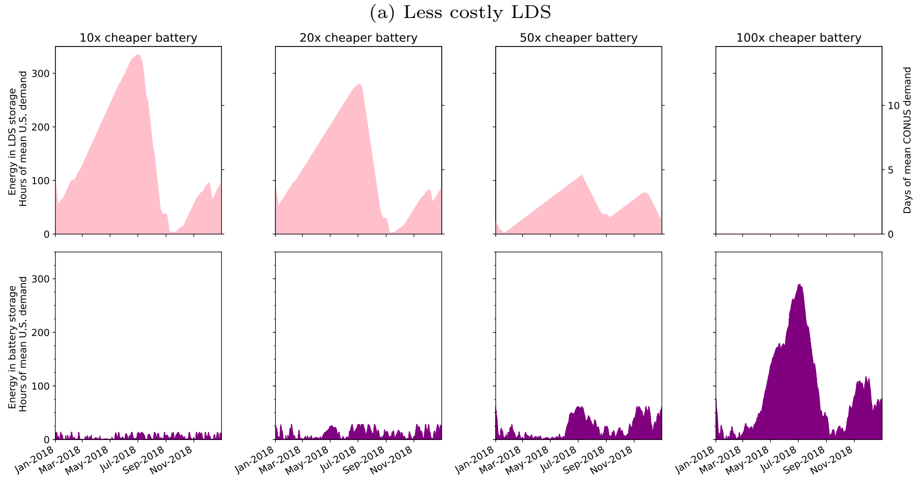


Figure S10: **Dispatched electricity as a function of LDS and battery costs.** a, b) LDS and c, d) battery costs were varied from four times (4x) more costly than base case assumptions (1x) to free (0x). Shares of electricity dispatched by each technology are shown on the y-axis. Total shares of electricity sources to the grid and those of electricity sinks from the grid are balanced for any hour in each simulation. The 49% round-trip efficiency of LDS is visually depicted in a, b) because the average power used for charging LDS was much larger than that obtained in discharging. This behavior can be compared to c, d) in which the 90% round-trip efficiency for batteries is evident. Cost contribution plots (Figure S9) in combination with power dispatch plots (Figure S10) allow determination of whether LDS's contribution to total system cost decreased because less LDS capacity was built or because LDS costs decreased.



(a) Less costly LDS



(b) Less costly batteries

Figure S11: **Cost-driven functional role dynamics.** This set of figures show energy stored in LDS and batteries at various costs. The top two rows of panels show that when LDS costs decrease at a factor of 4x, batteries disappear in the least-cost system. Despite lower LDS costs, LDS maintained its inter-season functional role, whereas batteries maintained their intra-day functional role. The bottom two rows of panels show that when battery cost is 100x cheaper, it is used more for inter-season storage than for purely intra-day storage, with the maximum energy stored in batteries reaching ∼300 h of mean contiguous U.S. demand.

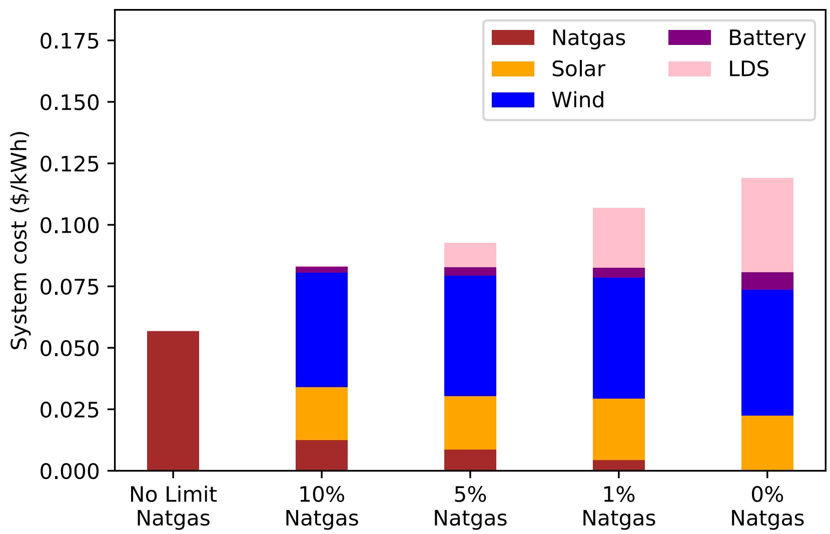


Figure S12: **Natural gas: System costs approaching a 100% decarbonized system.** A number of studies have shown that decarbonizing the electricity system becomes increasingly costly the close to 100% carbon-neutral the system is. We briefly explore these questions by allowing natural gas generators in our model but limit their annual dispatch to a fraction of total demand. We model 1) a system with current cost assumptions for natural gas with no limits on dispatch, 2) the same system with natural gas dispatch limited to 10% of annual demand, 3) natural gas limited to serving 5%, then 4) natural gas limited to 1% of demand. A reference bar is added that is the baseline no natural gas case modeled in the rest of this analysis. Stacked areas in each bar represent the cumulative contribution of each technology to total system cost over the optimization period (2018). Introduction of natural gas to the technology mix at 10% of demand minimizes or eliminates the need for storage. The system costs are: 1) 0.057 $/kWh, 2) 0.083 $/kWh, 3) 0.093 $/kWh, 4) 0.107 $/kWh, and 0.119 $/kWh for the reference case. Technical and economic inputs for natural gas are in Table S11.

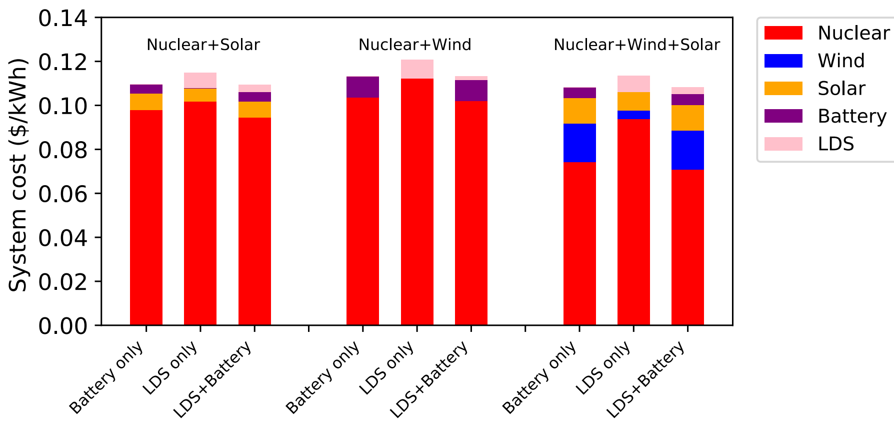


Figure S13: **Nuclear: System costs for different technology combinations.** In the left-most three bars, generation is provided only by solar energy and nuclear; in the middle three bars, by only wind energy and nuclear; and, in the right-most three bars, by a combination of solar, wind and nuclear resources. Within each grouping of three bars, the left-most bar represents a system with only LDS storage, the middle bar represents a system with only battery storage, and the right-most bar allows both storage technologies to compete. Stacked areas in each bar represent the cumulative contribution of each technology to total system cost over the optimization period (2018). Introduction of nuclear to the technology mix minimizes, but does not eliminate, the need for storage. Technical and economic inputs for nuclear are in Table S11.

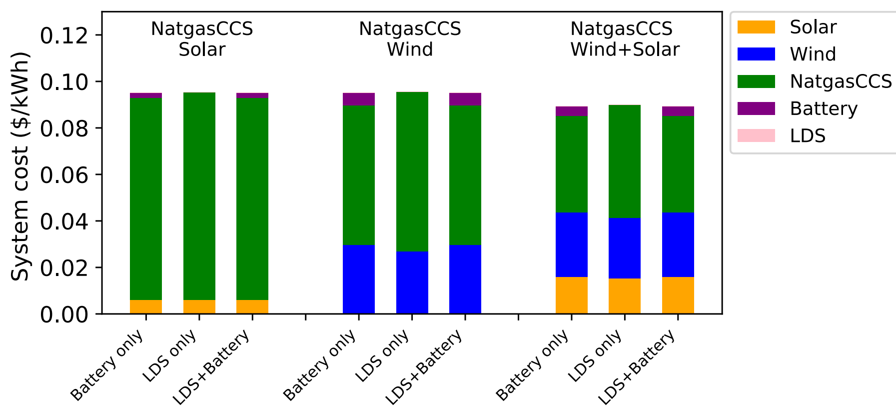


Figure S14: **Natural gas with carbon capture and storage (natgas CCS): System costs for different technology combinations.** In the left-most three bars, generation is provided only by solar energy and natgas CCS; in the middle three bars, by only wind energy and natgas CCS; and, in the right-most three bars, by a combination of solar, wind and natgas CCS resources. Within each grouping of three bars, the left-most bar represents a system with only LDS storage, the middle bar represents a system with only battery storage, and the right-most bar allows both storage technologies to compete. Stacked areas in each bar represent the cumulative contribution of each technology to total system cost over the optimization period (2018). Introduction of natgas CCS to the technology mix minimizes or eliminates the need for storage (especially LDS). Technical and economic inputs for natgas CCS are in Table S11.

4. Supplementary cost information

4.1. Base case long-duration storage technology: Power-to-Gas-to-Power (PGP) with renewable hydrogen

4.1.1. PGP underground storage

	Salt cavern (base case)	**Reference and comments**
Fixed capital cost ($)	7,434,940	Capital cost plus land costs for just the cavern (not compressor) H2A tab "Gaseous H_2 Geologic Storage" cell C217
Size (usable kg H2)	1,159,831	Default value in H2A model tab "Gaseous H_2 Geologic Storage" cell B103
Size (Energy rating, kWh)	45,697,341.40	Calculated here using the higher heating value (H2): 39.4 kWh/kg. From Hydrogen Delivery Scenario Model (HDSAM) V 3.1.
Fixed cost ($/kWh for storage)	0.16	Hydrogen Delivery Scenario Model (HDSAM) V 3.1. Note: Steward et al NREL report, (Table 3) quotes 0.16 $/kWh for dry mined salt caverns.
Lifetime (yrs)	30	Hydrogen Delivery Scenario Model (HDSAM) V 3.1.

Table S9: **Economic and technical assumptions for underground hydrogen storage.** Models and reports referenced.[31,32] This table supports Table 1. Figure 7b and Figure S8b show that results are not very sensitive to PGP energy capacity costs.

4.1.2. PGP electrolyzer + compressor combined fixed cost

Because electrolyzers and compressors are both power-rated conversion devices involved in the H_2 production step of PGP, we combined their fixed costs into one input variable for the model. To combine the fixed costs of electrolyzer and compressor devices, we determined the ratio of their system efficiencies as shown below.

Electrolyzer
Electrolyzer system efficiency = 67 kWh/kg[33]

Compressor
Design Flow to Each Compressor = 57,991 (kg/day)
Motor Rating per Compressor = 1,487 kW
Reference,[31] tab "Gaseous H_2 Geologic Storage", cell B138 and B145
Electricity required to compress 57,991 kg of H_2:
(1,487 kW) x 24 (h/day) = 35,688 kWh
Compressor system efficiency:
(35,688 kWh) / (57,991 kg H_2) = 0.6154 kWh/kg H_2

Electrolyzer / Compressor Ratio
Ratio of power consumption:
(67 kWh/kg) / (0.6154 kWh/kg) = 109
The electrolyzer consumes 109 times more power than the compressor for a given kg of H_2 that goes through the system. Thus, to combine the electrolyzer and compressor costs and put them into the units of the electrolyzer, we divide the fixed cost of the compressor by 109.

Combined fixed cost ($/kW for conversion)
Costs for electrolyzers and compressors in $/kW are in Table S10.
(1,045 $/kW) + (1392.2 $/kW)/109 = 1,058 $/kW
The combined electrolyzer + compressor fixed cost is represented as the H_2 production conversion cost in Table 1.

	Electrolyzer (PEM)	**Reference and comments**	**Compressor (Isentropic reciprocating)**	**Reference and comments**
Fixed capital cost ($)	118,258,606	Capital costs including O&M costs like labor PEM spreadsheet, tab "Capital costs", cell F36	2,070,236	H2A spreadsheet tab "Gaseous H_2 Geologic Storage" cell C182
Size (Power rating, kW)	113,125	Capital costs including O&M costs like labor PEM spreadsheet, tab "Capital costs", cell C41	1,487	H2A spreadsheet tab "Gaseous H_2 Geologic Storage" cell B182
Fixed cost ($/kW for conversion)	1,045 input into the electrolyzer[1]	Current Central Hydrogen Production from Grid PEM Electrolysis V3 2018	1392.2 used to compress[a]	Hydrogen Delivery Scenario Model (HDSAM) V 3.1
Lifetime (yrs)	10	Schmit, 2017[34]	15	H2A spreadsheet tab "Gaseous H_2 Geologic Storage" cell B160
Efficiency	70%	Current Central Hydrogen Production from Grid PEM Electrolysis V3 2018 tab "Process Flow" cell G12	100%	Assume no hydrogen leaks during compression.

Table S10: **Economic and technical assumptions for electrolyzers and compressors.** Models referenced include.[31,35] This table supports Table 1. Electrolyzer and compressor lifetime detail is available at the following link: `https://docs.google.com/spreadsheets/d/1nmrfp_s-C8Pqtqgyp3kgou2Pi8OtcXTFXiO-qWCvx9Q/edit?usp=sharing`.

[a]See electrolyzer + compressor combined fixed cost calculation. The electrolyzer consumes 109 times more power than the compressor for a given kg of H_2 that goes through the system. Thus, to combine the electrolyzer and compressor costs and put them into the units of the electrolyzer, we divide the fixed cost of the compressor by 109.

4.2. Firm generator technology costs

	Natural gas	**Natural gas with CCS**	**Nuclear**
Technology description	Conventional gas/ oil combined cycle	Advanced combined cycle with carbon capture and storage	Advanced nuclear
Total overnight capital cost [$/W]	982	2175	5946
Fuel cost [$/MMBtu]	3	3	-
Fuel cost [mills/kWh]	-	-	7.45
nth-of-a-kind heat rate [Btu/kWh]	6350	7494	10460
Fixed O&M cost [$/kW/yr]	11.11	33.75	101.28
Variable O&M cost [$/MWh]	3.54	7.20	2.32
Project life [yrs]	20	20	40
Calculated levelized costs			
Fixed cost [$/kWh]	0.012	0.027	0.065
Variable cost [$/kWh]	0.039	0.056	0.007

Table S11: **Economic and technical assumptions for natural gas, natural gas with CCS, and nuclear.** References included.[36–38] This table supports Figure S12, Figure S13, and Figure S14. An example calculation of fixed and variable costs for natural gas with CCS is in Table S12. Note: For nuclear we include only fuel costs as (in units of per kWh electricity not per kWh thermal) as variable costs and add all other non-fuel costs to the fixed cost.

4.2.1. Example calculation: natural gas with CCS fixed and variable cost

Variable cost calculation of natural gas with carbon capture and storage (NatgasCCS). This calculation supports Figure S14, Table S11, and Table S12.

Efficiency
Heat rate = 7493 (Btu/kWh)[36]
Heat content of electricity = 3412.14 (Btu/kWh)[39]
Efficiency: (1/7493) x 3412.14 = 0.4554

Fuel Cost
Fuel cost = 3 ($/MMBtu-thermal)[38]
Fuel cost = 0 (mills/kWh-electric)[38]
Heat content of electricity = 0.293 (MWh/MMBtu)[39]
Efficiency = 0.4554
Fuel cost ($/kWh-electric): (3/0.293/1000)/0.4554 + 0/1000 = 0.0225

Variable cost
Fuel cost ($/kWh-electric) = 0.0225
Efficiency = 0.4554
Variable O&M cost($/MWh) = 7.2[36]
Variable cost: (0.0225/ 0.4554) + (7.2/1000) = 0.0566

NatgasCCS: Fixed cost calculations	**Value**	**Reference and comments**
Capital cost ($/kW)	2175	EIA, AEO2018, Electricity Market Module, Table 2
Assumed lifetime (yrs)	20	EIA, AEO2018, Commercial Demand Module, Table 3
Capital recovery factor (% per year)	9.44%	Calculated with a discount rate of 0.07
Fixed O&M cost ($/kW-yr)	33.75	EIA, AEO2018, Electricity Market Module, Table 2
Fixed cost ($/kW-yr)	239.05	(capital cost * capital recovery factor) + fixed O&M cost
Fixed cost ($/kWh)	0.02727	Divide the cell above by hours in a year

NatgasCCS: Variable cost calculations	**Value**	**Reference and comments**
Fuel cost ($/MMBtu -thermal)	3	EIA, EPA2016, Table 7.20
Fuel cost (mills/kWh -electric)	0	EIA, EPA2016, Table 7.20
Heat rate (Btu/kWh)	7493	EIA, AEO2018, Electricity Market Module, Table 2
Efficiency	0.4554	Calculated here
Fuel cost ($/kWh -electric)	0.0225	Calculated here
Variable O&M cost ($/MWh)	7.2000	EIA, AEO2018, Electricity Market Module, Table 2
Variable cost ($/kWh)	0.0566	Calculated here

Table S12: **Economic and technical assumptions for natural gas with carbon capture and storage (NatgasCCS).** References included.[36–38] This table supports Figure S14 and Table S11.

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